

Summary of PSD Permits Issued To Electric Generating Units Addressing GHGs

Permit Seeker, Issuing Agency, & Date of Issuance	Type of Facility & Location	New or Existing Facility	GHG BACT Limits and Technologies Chosen	Technologies Eliminated	Additional Notes
<p>Taylorville Energy Center¹ (Tenaska/Christian County Generation)</p> <p>Illinois Environmental Protection Agency (October 17, 2011 – Draft)</p>	<p>602-MW IGCC coal gasification and power plant</p> <p>Illinois</p>	New	<ul style="list-style-type: none"> Plant-wide CO₂e: 5,031,409 tpy (CO₂: 4,990,000 tpy) Combined cycle units: <ul style="list-style-type: none"> – 2,307,110 tpy CO₂e on 12 month rolling basis; – 1200 lbs CO₂ per MWh on 12-month rolling basis Acid Gas Recovery Unit: 2,510,326 tpy CO₂e (includes limit for CO₂ vent of 111.4 tons/million SCF SNG) High efficiency CTGs Additional BACT limits for auxiliary boilers, etc. Tailgas recycling 	<ul style="list-style-type: none"> CCS technically infeasible (need to further develop technology, unresolved issues on sequestration, etc.) Not sequester CO₂ at beginning because prerequisites not present (lack of pipeline, etc.) Use of biomass as feedstock 	<ul style="list-style-type: none"> Will produce SNG Developer anticipates CO₂ will be geologically sequestered “at some point” and would preferably be used for EOR (Project Summary) Developer intends to build CCS facility in future but does not want it required in permit. May accept adjustable limit in final permit. Use of Illinois Basin coal critical for feasibility, meeting Clean Coal Portfolio Standard “CCS using EOR cannot be required as BACT since no CO₂ pipeline exists”
<p>Cricket Valley Energy Center²</p> <p>New York Department of Environmental Conservation (May 25, 2011 – Draft)</p>	<p>1,000-MW NGCC power plant</p> <p>New York</p>	New	<ul style="list-style-type: none"> 7,605 Btu/kWh annual net heat rate limit and thermal efficiency of 57.4% with no duct firing Combined cycle units: 3,576,943 tons CO₂e per rolling 12-month period Auxiliary boiler: 15,887 tons CO₂e/rolling 12-mo. period Fire pump: 114 tons CO₂e per rolling 12-month period High efficiency CTGs and HRSG Black start generator: 4,822 tons CO₂e per rolling 12-month period 	<ul style="list-style-type: none"> CCS (not commercially available or economically feasible) <ul style="list-style-type: none"> – No NGCC CO₂ absorption systems – Compression: increase CO₂ emissions, large parasitic load Lower emitting alternative technologies (not feasible) 	<ul style="list-style-type: none"> Draft permit contained no GHG BACT limits or efficiency design parameters; conditions listed were suggested by EPA Region 2 EPA Region 2 submitted comments on July 29, 2011; noted that was unaware of issuance of draft permit and had limited time to conduct review Total potential CO₂e emissions: 3,630,484 tpy CO₂ main source of GHGs; LAER used to address for CH₄ and N₂O emissions
<p>Abengoa Bioenergy Biomass of Kansas³</p> <p>Kansas Department of Environment and Health (March 2, 2011 – Draft)</p>	<p>120-MW biomass cogeneration facility</p> <p>Kansas</p>	New	<ul style="list-style-type: none"> BFB boilers: 0.40 lb CO₂e/lb steam produced based on 30-day rolling average Fermentation scrubber: 13,197 lb CO₂e/hr based on 30-day rolling average Distillation vent scrubber: 318 lb CO₂e/hr based on 30-day rolling average State-of-the-art SF₆ circuit breakers: 80.5 lb CO₂e/day Energy-efficient design 	<ul style="list-style-type: none"> Alternative emerging SF₆ technology (technically infeasible) Dielectric oil or compressed air circuit breaker (not feasible) CCS (not feasible or cost-effective) 	<ul style="list-style-type: none"> Uses biomass and natural gas for start up Potential to emit of 1,797,693 tons/yr CO₂e; total estimated CO₂e emissions of 1,731,399 BACT requirements exclude periods of startup, shutdown or malfunction Carbon capture, drying and compression projected to cost \$71/short ton avoided (compared to a value of \$41/short ton based on NETL report) 4 BFB boilers emit over 96% of total facility-wide CO₂e (CO₂, CH₄ and N₂O)
<p>Lower Colorado River Authority⁴</p> <p>EPA Region VI (TX) (November 10, 2011 – Final)</p>	<p>590-MW NGCC power plan (Thomas Ferguson plant)</p>	New (replacing existing plant)	<ul style="list-style-type: none"> 7,720 Btu/kWh annual net heat rate limit based on 365-day rolling average 0.459 tons CO₂/mWh (net) based on 365-day rolling average For each turbine: 	<ul style="list-style-type: none"> CCS (not feasible or cost-effective) Non-GHG substitutes for SF₆ 	<ul style="list-style-type: none"> Submitted GHG permit application to EPA in March 2011; draft permit issued on September 28, 2011 Heat rate limit similar to Russell City permit Use of heat rate and emissions standards required to measure efficiency of plant more accurately

	Texas		<ul style="list-style-type: none"> – CO₂: 908,957.6 tons/year – CH₄: 16.8 tons/year (353.3 tpy CO₂e) – N₂O: 1.7 tons/year (521.6 tpy CO₂e) • High efficiency CTGs and HRSG • Plant-wide energy efficiency practices and designs • Includes limits for fugitive emissions, emergency generator, fire water pump, circuit breakers, etc. 		<ul style="list-style-type: none"> • Replace 440-MW unit with new plant • CCS could increase cost of project ~42% (~\$230 million) • CCS can be considered “available” for purpose of BACT analysis (Statement of Basis) • Will increase emissions by 2 million tpy
<p>Palmdale Hybrid Power Project⁵</p> <p>EPA Region IX (CA) (October 18, 2011 – Final)</p>	<p>570-MW NGCC power plant + 50 MW solar plant</p> <p>California</p>	New	<ul style="list-style-type: none"> • CO₂: 774 lb/MWH source-wide net output based on 365-day rolling average (for each CTG) • 7,319 Btu/kWh source-wide net heat rate based on 365-day rolling average (for each CTG) • CO₂e: 1,913,000 tpy • Solar component required part of facility 	<ul style="list-style-type: none"> • CCS (economically infeasible) – would cost twice as much as the facility’s annual capital costs • Lower emitting alternative technologies (determined to be infeasible) 	<ul style="list-style-type: none"> • First permit to incorporate CO₂ lbs/MWH limit • Solar component is considered to be part of the GHG BACT determination for the combustion turbines and associated heat recovery system • No GHG BACT analysis performed for CH₄, N₂O or SF₆, since emissions are negligible (< 0.3% of facility GHG CO₂e emissions); CO₂ main source of GHGs • GHG limits based on operation at maximum permitted level; use of solar array will reduce GHG emissions below estimated rate
<p>Robinson Power Company</p> <p>Pennsylvania Department of Environmental Protection (June 30, 2011 – Final)</p>	<p>148-MW NGCC power plant</p> <p>Pennsylvania</p>	New	<ul style="list-style-type: none"> • CO₂e: 619,360 tpy based on 12-month rolling average and 70.7 tons/hr based on 60-minute average • No BACT analysis required (not a major source of attainment pollutants other than GHGs) 		<ul style="list-style-type: none"> • GE 7EA natural gas-fired CTGs • Plant will use fuel from Marcellus shale • Permit issued 1 day before Phase II CAA GHG permit requirements took effect, which would require GHG PSD permit and BACT analysis • Plant will emit 620,000 tpy of CO₂
<p>Wolverine Power Supply Cooperative⁶</p> <p>Michigan Department of Environmental Quality (June 29, 2011 – Final)</p>	<p>600-MW coal- and biomass-fired power plant (Wolverine Clean Energy Venture)</p> <p>Michigan</p>	New	<ul style="list-style-type: none"> • CO₂e emissions limit of 6,024,107 tons/year based on 12-month rolling average • CO₂e emissions limit for each CFB boiler of 2.1 lb/KWH gross output based on 12-month rolling average • Energy efficiency for CFB boilers and ancillary fuel burning equipment • Minimum of 5% biomass in the feedstock (20% max); Biomass Fuel Management and Procurement Plan • Energy-efficient variable speed motors • Design specifications that maximize thermal performance of plant • Energy Efficiency Management Plan 	<ul style="list-style-type: none"> • CCGT (redefine source) • Pulverized coal (redefine project) • IGCC (cost prohibitive; no clear advantage) • Biomass gasification (infeasible – limited available fuel source) • CCS (not feasible or cost effective) • Supercritical CFB (beyond BACT scope) • Use of design technologies other than CFB boiler not justified 	<ul style="list-style-type: none"> • Uses CFB boilers – more feasible and cost-effective • Potential to emit of 6,050,090 tpy CO₂e • “Most GHG emission reduction technologies remain highly developmental and are not suitable at this time to be...BACT” • Many technologies eliminated because did not take advantage of site-specific criteria • CCGT would substantially increase consumer rates • Permit initially denied in 2010 based on lack of need. Denial reversed by county court in early 2011. • Sierra Club and NRDC filed challenge in MI state court on 09/26/11
<p>MidAmerican Energy Company⁷</p> <p>Iowa Department of Natural Resources</p>	<p>644-MW coal-fired power plant (George Neal South)</p>	Existing (Unit 4)	<ul style="list-style-type: none"> • CO₂ emissions limit: 2,588 lb/MWH-net based on a 30-day rolling average • CO₂e emissions limit: 6,807,782 tpy based on 12-month rolling average • Efficiency improvements 	<ul style="list-style-type: none"> • Catalytic oxidation and thermal oxidation (technically infeasible) • CCS (not technically or financially feasible) • Thermodynamic cycle design and 	<ul style="list-style-type: none"> • GHG emissions (CO₂, CH₄ and N₂O) expected to increase ~2 million tons/year CO₂e • CO₂ limit established as surrogate to demonstrate compliance with CO₂e standard (CO₂ expected to be 99% of unit’s global warming potential)

(May 16, 2011 – Final)	Iowa			IGCC (redefine source) • Coal rank utilized (would not decrease CO ₂ e emissions)	• Compliance determined by summing CO ₂ CEMS data with CH ₄ and N ₂ O mass emissions calculations
PacifiCorp⁸ Utah Department of Environmental Quality (May 4, 2011 – Final)	629-MW NGCC power plant (Lakeside) Utah	New (co-located with existing facility)	<ul style="list-style-type: none"> • CO₂e emissions limit of 950 lb/MWH based on a 12-month rolling average • High efficiency CTGs and HRSG • Use of low-NO_x controls 	• CCS (not technically or financially feasible at this time)	<ul style="list-style-type: none"> • Adding new unit (2 turbines) expected to increase power plant GHG emissions by 1.8 million tons/year CO₂e • “All BACT reviews for GHGs have focused on energy efficiency”
We Energies⁹ Wisconsin Department of Natural Resources (March 28, 2011 – Final)	50-MW biomass cogeneration facility (Domtar Paper Mill-Rothschild) Wisconsin	New	<ul style="list-style-type: none"> • CO₂ emission limit of 3,050 lb/MWH based on a 12-month rolling average • Efficient boiler operation/good combustion practices • Use of biomass/renewable fuels • Use of NO_x controls • Use of natural gas boiler 	<ul style="list-style-type: none"> • CCS (not feasible) • Methane oxidation (not required due to cost) • Natural gas would redefine project 	<ul style="list-style-type: none"> • No suitable CO₂ storage near site • No examples of large-scale commercially available CCS • CFB is most efficient boiler design for biomass boiler
Russell City Energy Center (Calpine) Bay Area Air Quality Management District (February 3, 2010 – Final)	600-MW natural gas power plant (Russell City) California	New facility	<ul style="list-style-type: none"> • CO₂e emission limit for turbines: 1.928 MMT/yr • Heat rate limit for each turbine: 7,730 Btu/KWH • State-of-the-art SF₆ circuit breakers: 39.3 metric tons CO₂e based on 12-month rolling average • Use of most efficient fire pump engine: 7.6 metric tons CO₂e based on 12-month rolling average • Use of most efficient generating technology (natural gas) 	<ul style="list-style-type: none"> • Non-fossil fired generation (not feasible) • CCS (not feasible) • Dielectric oil or compressed air circuit breaker (not feasible) 	<ul style="list-style-type: none"> • Based on voluntary GHG BACT requirements • At present there are no feasible post-combustion add-on controls for such facilities • Statement of Basis notes that BACT limit “needs to be ‘output-based’ instead of just an absolute limit on [GHG] emissions”; permit requires both absolute mass emissions limits and heat rate limits

BACT – Best Available Control Technology
 BFB – bubbling fluidized bed
 CCGT – combined-cycle gas turbine
 CCS – carbon capture and storage
 CFB – circulating fluidized bed
 CO₂e – carbon dioxide (CO₂) equivalent
 CTG – combustion turbine generator
 ESP – Electrostatic precipitator
 FGD – flue gas desulfurization

GHG – greenhouse gas
 HRSG – Heat Recovery Steam Generators
 MMT – million metric tons
 NGCC – natural gas-fired combined-cycle
 PSD – Prevention of Significant Deterioration
 SNCR – selective non-catalytic reduction
 SNG – Substitute natural gas
 TPY – tons per year

¹ Includes GHG BACT limits for: cold, warm and hot start and shutdown; coal bunker vents (8,217 tpy); coal dryers (78,523 tpy); auxiliary boiler (74,013 tpy and energy efficient boiler design); oxidizer/sulfur recovery unit (4,937 tpy); equipment leaks (good work practices and 1,255 tpy); emergency engines; flares (Flare Minimization Plan); use of good operating practices, etc. Project Summary notes that “carbon capture has not been commercially demonstrated in the power generation sector in baseload or full stream applications” and that “post-combustion capture has only been demonstrated on small slip streams for limited periods.” Other reasons cited why CCS not feasible included that geologic formations are not being used to sequester CO₂ in absence of EOR, that demo projects are needed to further develop and refine CCS technology, and the lack of a national CO₂ control program.

² Lower emitting alternative technologies that were analyzed and eliminated included wind, additional solar, geothermal, hydro, nuclear, biomass and simple cycle combustion turbines. Reasons given why sequestration was not technically feasible included: no access to suitable sequestration site; gov’t funding needed for CCS infrastructure; and, lack of transportation infrastructure

- ³ Includes GHG BACT limits for: Ash pelletizer dryer (1,124 lb CO₂e/hr based on 30-day rolling average); NFPA-20 certified firewater pump engine (24 tons CO₂e/yr during any 12-month consecutive period); biogas flare (248 tons CO₂e/yr during any 12-month consecutive period). BACT for energy-efficient design incorporates cogeneration, process integration, combustion of co-products, heat recovery, and operational and maintenance monitoring, and applies to the BFB boilers, ash pelletizer dryer, and fermentation and distillation bent scrubbers. GHG BACT for BFB boilers also includes use of low-carbon and carbon-neutral fuels, restricted to those with low to no economic value, or lower impacting crops, and the use of natural gas for startup. GHG BACT for ash pelletizer dryer and biogas flare also includes restricting fuel type to pipeline-grade natural gas (and to biogas for flare). GHG BACT options eliminated included: for SF₆ circuit breakers – emerging alternative technology, use of dielectric oil (technically infeasible) and oil/air-blast breakers (adverse environmental impacts); CCS – precombustion, oxygen-fired and various post-combustion capture processes (technically infeasible), post-combustion capture with chemical absorption (not cost-effective), carbon storage and beneficial use (not evaluated since capture not found to be cost-effective).
- ⁴ Includes GHG BACT limits for: Fugitive emissions – 16.2 tpy of CH₄ (327.2 tpy CO₂e); emergency generator – 15,314 lbs/hr CO₂ (766 tpy CO₂e); fire water pump – 7,052 lb/hr CO₂ (352.6 tpy CO₂e); State-of-the-art SF₆ circuit breakers – 131 tpy CO₂e. Includes work practice and operational requirements for fire pump and emergency generator, and separate standards for startup and shutdown emissions
- ⁵ Includes GHG BACT limits for SF₆ circuit breakers (9.56 tpy CO₂e based on 12-month rolling average) and requirements for annual boiler tune-ups, and the use of high efficiency CTGs and HRSG. Lower emitting alternative technologies that were analyzed and eliminated included wind, additional solar, geothermal, hydro, nuclear and biomass. GHG BACT options eliminated as part of CCS included solvent-, sorbent- and membrane-based capture processes, geologic sequestration, ocean storage and mineral carbonation (all determined to be technically infeasible). CO₂ transportation was found to be commercially available.
- ⁶ Plant will consist of two 300-MW CFB boilers using sub-bituminous coal and biomass. GHG BACT selected also included use of proper management of renewable resources (e.g., biomass). BACT analysis found that pulverized coal, IGCC and biomass gasification technologies would increase CO₂ emissions over CFB design. CCS BACT analysis examines and eliminates the following capture technologies as not being demonstrated on the scale needed: chemical, physical and hybrid technologies for absorption (including amine and ammonia-based); adsorption; physical separation; biological uptake; and oxyfiring. CCS BACT analysis also examines and eliminates geologic (in part due to unresolved liability issues) and terrestrial sequestration technologies. GHG sources listed: CFB boilers, auxiliary boiler, emergency firewater pump engine and emergency generator, and black start generator. Lawsuit by environmental groups claims that GHG BACT analysis is flawed because it failed to require use of cleaner fuels.
- ⁷ Permit required as a result of installation of SNCR, FGD, baghouse and other controls on Unit 4, which began operating in 1979. BACT requirements include workplace manual detailing efficiency improvements identified as BACT (replacement of low-pressure turbine components, reduced ESP use, etc.). Plant efficiency improvements eliminated as BACT included (reason why in parenthesis): cooling system heat loss recovery (would redefine the source), flue gas heat recovery (additional recovery technically infeasible), low-rank coal drying (technically infeasible for coal currently being used) and combined heat and power plant (not technically feasible). Pollution control device improvements that were eliminated as BACT: switching to a wet FGD system (no impact on net GHG emissions) and use of ammonia in SNCR system (safety aspects of using urea outweigh small possible CO₂ reduction). CCS BACT analysis examines and eliminates the following capture technologies: pre-combustion (not technically feasible), oxygen-combustion (would redefine the source) and post-combustion (no system applied to large power plant yet). CCS BACT analysis also examines and eliminates the following sequestration technologies: mineral, hydrodynamic and solubility trapping.
- ⁸ Utah DEQ notes that using a GHG emission limit, which would represent the potential to emit, for BACT “adds no value to the resulting permit.” However, CO₂e emissions limit added “in this instance” at request of PacifiCorp. The Intent To Approve (ITA) issued by Utah DEQ did not set a CO₂ emissions standard or limit, though it noted that the plant would surpass the California GHG emissions standard of 1,100 lbs/ per MWH of gross output for baseload power plants. The acceptance in the ITA of high efficiency CT natural gas boiler as BACT for GHGs had suggested the use of a design standard in lieu of emissions standard.
- ⁹ We Energies permit emissions limits based on CO₂e emissions per 1,000 pounds of steam produced for natural gas boiler of 190 lb/1,000 lb steam produced, and 3,050 lb per MWH of gross output for biomass boiler.